Low NOx/SOx Burner Retrofit for Utility Cyclone Boilers

Quarterly Technical Progress Report
October - December, 1990

Reference Cooperative Agreement
DE-FC22-90PC89661

TransAlta Technologies

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED
Low NOx/SCx Burner Retrofit for Utility Cyclone Boilers

Quarterly Technical Progress Report
October - December, 1990

Reference Cooperative Agreement
DE-FC22-90PC89661

Patents Cleared by Chicago
on July 11, 1991
## CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0 Introduction</td>
<td>1</td>
</tr>
<tr>
<td>2.0 Process Design</td>
<td>2</td>
</tr>
<tr>
<td>3.0 LNS Burner Design</td>
<td></td>
</tr>
<tr>
<td>3.1 LNS Burner Thermal Analysis</td>
<td>4</td>
</tr>
<tr>
<td>3.2 Mechanical Design</td>
<td>5</td>
</tr>
<tr>
<td>3.3 Burner-Boiler Flow Modelling</td>
<td>6</td>
</tr>
<tr>
<td>3.4 Slag Screen Design</td>
<td>10</td>
</tr>
<tr>
<td>4.0 Balance of Plant Engineering</td>
<td></td>
</tr>
<tr>
<td>4.1 Architectural Work</td>
<td>13</td>
</tr>
<tr>
<td>4.2 Civil and Structural Design</td>
<td>13</td>
</tr>
<tr>
<td>4.3 Mechanical Design</td>
<td>14</td>
</tr>
<tr>
<td>4.4 Electrical Design</td>
<td>15</td>
</tr>
<tr>
<td>4.5 Instrumentation and Control</td>
<td>16</td>
</tr>
<tr>
<td>4.6 Procurement</td>
<td>17</td>
</tr>
<tr>
<td>4.7 Construction and Installation</td>
<td>18</td>
</tr>
<tr>
<td>5.0 Boiler Modifications</td>
<td>19</td>
</tr>
<tr>
<td>6.0 Baseline Test</td>
<td></td>
</tr>
<tr>
<td>6.1 Introduction</td>
<td>23</td>
</tr>
<tr>
<td>6.1.1 Management of Baseline Test Program</td>
<td>23</td>
</tr>
<tr>
<td>6.1.2 Pretest Activities</td>
<td>23</td>
</tr>
<tr>
<td>6.2 Baseline Testing</td>
<td>24</td>
</tr>
<tr>
<td>6.2.1 Performance Test No. 1</td>
<td>24</td>
</tr>
<tr>
<td>6.2.2 Performance Test No. 2</td>
<td>25</td>
</tr>
<tr>
<td>6.2.3 Performance Test No. 3</td>
<td>26</td>
</tr>
<tr>
<td>6.3 Boiler Performance Test</td>
<td>27</td>
</tr>
<tr>
<td>6.3.1 Boiler Performance Results</td>
<td>28</td>
</tr>
<tr>
<td>6.4 Material Monitoring Program</td>
<td>28</td>
</tr>
<tr>
<td>6.4.1 General Boiler Condition</td>
<td>29</td>
</tr>
<tr>
<td>6.5 Environmental Monitoring</td>
<td>30</td>
</tr>
<tr>
<td>7.0 Boiler Maintenance</td>
<td>33</td>
</tr>
<tr>
<td>8.0 Technology Transfer</td>
<td>35</td>
</tr>
<tr>
<td>9.0 Work Planned for Next Period</td>
<td>36</td>
</tr>
</tbody>
</table>
FIGURES

1 Schematic of LNS Burner Boiler Interface
2 Temperature Isolines, 12-feet Above Slag Screen
3 Temperature Isolines at Superheat Region
4 Temperature Profile at Superheat Region
5 Slag Screen Tube Layout
6 Architectural Elevations
7 Architectural Elevations
8 Topping Out Ceremony - Fuel Preparation Building
9 Stack Monitoring Platform
10 Bucket Elevator Support Steelwork
11 Replacement of Boiler Floor Tubes by SIPC
12 Relocation of Coal Feeders
13 Atrita Pulverizer
14 Fuel Transport Blower
15 Air Cannons
16 Coal Separator Cyclones
17 Setting Limestone Silo
18 Boiler Front Wall Tubes
19 Gas Pass Ducting Supports

APPENDICES

A. Technology Transfer Paper
1.0 INTRODUCTION

This report is the second in the series of Quarterly Technical Progress Reports to be issued to the U.S. Department of Energy and other Funding Parties in accordance with the requirements of the Cooperative Agreement for this project, (DOE Instrument Number DE-FC22-90PC89661). It covers the period from October 1, 1990 to December 31, 1990.

Most of the emphasis during this reporting period was on preparation for the Baseline Test Program, the execution of the tests and the analysis and documentation of data obtained during the tests. Some preliminary results are discussed in this report, but because of the large volume of data to be analyzed and the extensive nature of the reports required, this work will continue into the next reporting period.

Technical activities during the period included thermal analysis and the preparation of fabrication drawings for the LNS Burner, LNJ Burner-boiler flow modelling and the development of a slag screen model. Boiler modifications necessary to ensure the availability of Unit 1 boiler during the Project Demonstration Phase were identified and a boiler maintenance program was established.

Site construction continued with the erection of the Fuel Preparation Building, procurement and installation of major equipment and modifications to the Unit 1 boiler by Southern Illinois Power Cooperative.
2.0 PROCESS DESIGN

The initial results of the Baseline Test of Marion Unit 1 were obtained during the current reporting period. The preliminary results are presented below in Table 2.0-1 and show that the performance of the unit is lower than predicted as the carbon in flyash is much higher than expected. As the boiler efficiency calculated using the ASME PTC 4.1 methodology is significantly affected by these carbon losses, these samples are being reanalyzed. The boiler efficiency will then be reassessed if required. However, the predicted retrofitted boiler efficiency of 88.05% using the LNS Burner is not expected to change since the carbon burnout is expected to be nearly complete.

The boiler efficiency comparison between the current cyclone boiler (original design and Baseline results) and the estimated efficiency after the retrofit are shown below. The values for the major unit input and output streams are also indicated. Please refer to Section 6.0 for further discussion of the Baseline Test results.

<table>
<thead>
<tr>
<th>Marion Unit 1</th>
<th>Original Design Basis</th>
<th>LNS Burner Retrofit Basis</th>
<th>Baseline Test Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stream Flow, lb/h</td>
<td>335,000</td>
<td>335,000</td>
<td>314,936*</td>
</tr>
<tr>
<td>Coal Flow, lb/h</td>
<td>37,000</td>
<td>38,074</td>
<td>44,595*</td>
</tr>
<tr>
<td>Limestone, lb/h</td>
<td>0</td>
<td>6,889</td>
<td>0</td>
</tr>
<tr>
<td>Other Additive, lb/h</td>
<td>0</td>
<td>1,341</td>
<td>0</td>
</tr>
<tr>
<td>Total Combustion Air, lb/hr</td>
<td>331,500</td>
<td>341,160</td>
<td>392,940*</td>
</tr>
<tr>
<td>Boiler Excess Air, %</td>
<td>16</td>
<td>16</td>
<td>17.2*</td>
</tr>
<tr>
<td>Slag Collected, lb/h</td>
<td>3,780</td>
<td>9,138</td>
<td>5,949*</td>
</tr>
<tr>
<td>Flyash Collected, lb/h</td>
<td>2,440</td>
<td>2,245</td>
<td>3,956*</td>
</tr>
<tr>
<td>Stack Flyash Emissions, lb/h</td>
<td>80</td>
<td>40</td>
<td>176</td>
</tr>
<tr>
<td>Boiler Efficiency (net), %</td>
<td>88.45</td>
<td>88.05</td>
<td>82.65*</td>
</tr>
<tr>
<td>Combustible Refuse Loss, %</td>
<td>0.1</td>
<td>&lt;0.1</td>
<td>6.79*</td>
</tr>
</tbody>
</table>

* Calculated in accordance with ASME PTC 4.1 (Abbreviated)
Meetings were held to discuss control philosophy and requirements with all Project Team Members, including cyclone boiler consultants and operators. The information presented in the feasibility study on incorporating the LNS Burner into Marion Unit 1 was reassessed. A review of existing plant operating procedures and policies continued during the reporting period.

No work will be done in updating the material and energy balances until after the Baseline Test results have been finalized. At that time, equipment performance characteristics, such as air heater leakage, can be evaluated and updated as necessary.
3.0  LNS BURNER DESIGN

Effort during the current reporting period was focussed on the analysis of LNS Burner heat transfer, continuing development of fabrication drawings, LNS Burner-boiler flow modelling and development of a slag screen model. These design and analysis tasks will be discussed in the following sections.

3.1  LNS BURNER THERMAL ANALYSIS

The LNS Burner thermal model has been developed and is being used to evaluate thermal profiles and startup conditions. Three modules were developed: LNS Burner, modified cyclone barrel and a combined system. Each module covers specific tasks: the LNS Burner model is used to validate refractory thickness, cooling air gap design and the overall fabrication design; the cyclone barrel model is used to validate refractory thickness and overall heat balance to the cooling water circuit; and the system module is used to evaluate startup and cool-down transients.

Each model uses a commercially available thermal analyzer program to solve the finite difference equations and to determine the temperature distribution. The module incorporates thermal convection and radiation from the hot gas to the refractory hotface, conduction across refractory material, convection and radiation across the cooling gap (LNS Burner model) conduction across the outer thermal insulation, convection and radiation from the insulation to the environment and energy transport into the cooling media. Input variables are provided for different material properties, transport properties, process conditions, and physical geometries, such as annulus thickness, refractory thickness, etc. A schematic of the LNS Burner showing the refractory details and its interface with the boiler is shown in Figure 1.

The initial results of the LNS Burner module are presented in the attached table. Also included are the design goals including maximum metal wall temperature, air temperature and refractory limits. Two operating conditions were examined: 100% MCR and 50% MCR. The most
severe operating conditions for the LNS Burner design is at part load when the amount of air available to cool the inside surface of the metal wall is reduced which in turn reduces the convective heat transfer coefficient. The design requirements and model predictions are presented in Tables 3.1-1 and 3.1-2.

<table>
<thead>
<tr>
<th>Table 3.1-1 100% Load Condition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Location</td>
</tr>
<tr>
<td>Metal wall temperature</td>
</tr>
<tr>
<td>Air preheat temperature</td>
</tr>
<tr>
<td>Zone between dense/insul. mat'lı</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 3.1-2 50% Design Condition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Location</td>
</tr>
<tr>
<td>Metal wall temperature</td>
</tr>
<tr>
<td>Air preheat temperature</td>
</tr>
<tr>
<td>Zone between dense/insul. mat'lı</td>
</tr>
</tbody>
</table>

Work for the following period will use the system model to evaluate startup and cool-down transients. The model will also be used to evaluate operation from initial preheat with oil igniters; initial operation with coal; ramp up to operating conditions under turbine load; and the effects of normal shutdown and the consequences of a unit trip.

3.2 MECHANICAL DESIGN

Effort continued in updating the LNS Burner fabrication drawings. Thermal design requirements, refractory selection and support, coal injector design issues, design requirements for the cooling annulus and special features design continue to be reassessed.

The fabrication drawings for the LNS Burner have been completed and are being carefully checked. Plans for the next reporting period are to
make an independent structural assessment to check the fabrication drawings against the design and operating requirements.

3.3 BURNER-BOILER FLOW MODELLING

Cyclone furnaces operate with high excess air and at high temperature. The heat release during combustion is very high and as a result, the boiler volume is much smaller than would be found in a conventional pc-fired system. The Marion Unit 1 boiler, at the level of the cyclone entry, has a small cross-section; about 5-feet in depth and about 20-feet in width. A boiler schematic showing the LNS Burner and relative location of the superheater region and overfire air ports is shown in Figure 1.

The LNS Burner's combustion process is fundamentally different from that of the cyclone, and the combustion products are also different. The LNS Burner products enter the boiler as hot, fuel-rich gases. Additional overfire air must be added to complete this combustion step with care taken to avoid the formation of thermal NO\(_X\). If done correctly, SO\(_2\) is controlled and significant NO\(_X\) reductions are achieved. Because of the small boiler volume, flow modelling was found to be necessary to insure that adequate mixing of LNS Burner combustion products with air can be accomplished to achieve NO\(_X\) emissions goals.

Design requirements for the air injection system for the Marion boiler were developed using FLUENT, a commercially available computational fluid dynamics (CFD) code. A series of runs were made to obtain a design for final air injection that met the process design goals as closely as possible.

A primary design goal for the overfire air (OFA) system is to control gas temperatures at the boiler superheat region to the same temperatures that existed in prior cyclone boiler operation (1900 - 2200\(^\circ\)F). Constraints on this goal took two forms: the physical geometry of the boiler and process considerations. The physical constraint was the small depth of the lower boiler at Marion, which offers a limited volume for mixing air into the gases exiting from the LNS Burner. Air addition within the boiler must be
carefully controlled in order to limit the formation of thermal NO\textsubscript{x} until the flue gas reaches the superheat region. Additionally, as the design matured a concern developed over gas temperatures in the lower boiler relative to slag fusion points. A new design goal was added to insure gas temperature below the slag screens was above slag fusion points to guarantee that slag from the combustors will flow properly to and through the slag tap located in the boiler floor.

FLUENT is a finite difference code used for solving the Navier-Stokes equations within a computational domain. It can treat 3-dimensional, steady, turbulent flows with chemically reacting components and convective/radiation heat transfer at boundaries. This combination of physical modelling abilities corresponds to the requirements for designing the Marion air injection system.

Because of the scale difference between small air ports and overall boiler dimensions, simulation of boiler flow fields inevitably leads to large models which translates directly to long computer execution times needed to achieve a reasonably converged solution. A goal when using CFD codes is to maximize the node size (coarse grid) which minimizes the number of nodes and yet keeps the computational errors within bounds. Small jets entering and mixing in large volumes make this a difficult task. For the Marion boiler, right-left symmetry allowed a half-width model (sidewall to boiler centerline) to be used. This helped reduce the number of nodes. However, the need to mix air within the entire boiler volume meant that the model had to cover the full height and depth.

Two models were used in the development of design requirements: first a model with 79,092 nodes (Runs 1 through 3); and a second model (Run 4 and following) with 116,480 nodes. The first, simpler model used 78 nodes from floor to roof (56.1 feet); 26 nodes from front wall to rear wall (12 feet); and 39 nodes from sidewall to boiler centerline (9.25 feet). The second, more detailed model used 80 nodes from floor to roof; 26 nodes from front wall to rear wall; and 56 nodes from sidewall to boiler centerline. The proportionately larger numbers of nodes in the sideways direction was needed to accommodate non-symmetrical air injection locations. The
change in node number reflected a change in the slag screen design and
elevation of the OFA relative to the evaporative rear platens in the boiler.

In Run 1, the OFA ports were placed fairly low on the boiler rear wall
to give maximum mixing length for the OFA. The OFA was directed
horizontally toward the front wall because of the short boiler depth at this
elevation. This run showed poor results with significant channelling of hot
LNS Burner gas. This hot gas easily reached the low OFA ports creating a
very non-uniform temperature field for the OFA to penetrate. OFA
penetration itself was excellent. Clearly the OFA was placed too near the
centerline elevation of the LNS Burners.

Run 2 increased the number of air ports from three to five. The OFA
was raised on the rear wall to put more tempering distance between the
OFA and the LNS Burner gas flow. The LNS Burner gas still channelled
heavily at the OFA level with an uneven temperature field.

The concept explored in Run 3 was a "dynamic cap" approach. The
air was directed horizontally rather than down and inward toward the slag
screen flow. The idea was to form a fairly complete screen of air through
which the LNS Burner gas must flow forming fewer and smaller channels
of hot gas. The results showed some improvement in smoothing the
temperature field, but not enough to be called a success.

Starting with Run 4, the more detailed 116,480 node model was used.
Also, at this time, the slag screen design underwent changes resulting in
hotter exiting temperatures and higher velocities than the earlier design.
The new slag screen layout also meant that a finer node spacing in the
sideways direction was needed which could also accommodate more control
over lateral placement of air ports.

Because of the new slag screen exit conditions, the Run 4 geometry
was reassessed, and OFA was raised to its maximum possible elevation,
just below the entrance to the superheaters. Additionally, the OFA was
directed downward at 45° to minimize direct carry-over into the
superheater inlet with this high OFA placement. The OFA showed no
significant loss of penetration with this directional change. The results
again showed excessive channelling of hot LNS Burner gas which creates a high and uneven temperature field. The channels were at each sidewall and at the boiler centerline. Subsequent designs dealt directly with breaking up these hot channels.

The concept modelled in Run 5 was changed with additional ports and further modified conditions. These new ports were added expressly to break up the hot gas channels noted in Run 4 at the sidewalls and the boiler centerline. The results showed only a small improvement over the geometry used in Run 4. The three hot channels continued to exist and showed high temperatures.

The geometry used in Run 6 focused entirely on the hot channel issue since previous geometries showed that a few ports above the slag screens directed down into the LNS Burner flow effectively reduced burner gas temperatures above each burner centerline to acceptable levels. Three ports were now located on the rear wall near the boiler centerline at the same elevation as the front wall above the slag screens. These three ports directly attack the dominant hot channel flow predicted in Runs 4 and 5 at the boiler centerline. The results showed good success at breaking up this center hot channel, but the temperature field remained unacceptable with values too high at the sidewall.

Run 7 addressed the problem of hot channels in each sidewall-rear wall joint with the addition of air ports. Additionally, this geometry corrected an error in wall boundary conditions for the lower third of the boiler. All earlier geometries had used a wall condition for heat transfer to bare waterwalls throughout the entire boiler from floor to roof. The presence of refractory and slag on the walls of the lower third of the boiler was addressed in this run. In this run and all subsequent runs, a better estimate for the adiabatic wall boundary condition in the lower third of the boiler was used. The results from Run 7 showed that the air port configuration gave a relatively smooth temperature field at the OFA level, although values of 2400°F to 2700°F were higher than the desired 2200°F. Additionally, the results predicted a temperature field of 2000°F to 2300°F below the slag screens, a range coincident with typical slag fusion points. This gave rise to a new concern and design goal: to raise the temperatures
near the floor above any possible slag fusion point to minimize problems with slag flowing from the burners to the slag tap in the rear center of the floor.

Temperature isolines maps for the boiler region are presented in Figures 2 through 4. The isolines in plan view for the region 12 feet above the slag screen are shown in Figure 2. The peak temperatures are about 2900°F. As shown in Figure 3, these peak temperatures are reduced to about 2000°F at the bottom of the superheat region. Figure 4 shows the change in temperature across the OFA ports as final air is added.

In the next reporting period, the final results of the boiler flow modelling and the resultant design features will be discussed. The planned work is to focus on mixing air within the lower boiler volume to insure sufficient for proper operation of the slag tap and to maintain the gas temperature in the superheat region at the 2200°F goal.

3.4 SLAG SCREEN DESIGN

The slag screen uses principles developed during prior work to remove slag droplets from hot LNS Burner gases exiting into the boiler volume. The hot gas with entrained molten slag flows through the old cyclone furnace barrel and impacts the slag screen at the boiler water wall. The slag screen is composed of vertically staggered, refractory-covered, water wall tubes. See figure 5 for a typical cross section of the slag screen. The slag screen functions by causing entrained molten slag to impact and stick on the tubes. The slag then flows by the tubes and into the slag tap at the bottom of the boiler.

Development of the slag screen thermal-hydraulic model continued during this reporting period. The model uses a commercially available thermal analyzer program to solve finite difference equations to evaluate the temperature flow field. The model can predict thermal performance of the slag screen by coupling the hot gas containing molten slag droplets to the slag screen by convection and radiation. Hydraulic performance of the slag screen is calculated by the model.
The model uses a finite difference method approach with a relaxation method to solve the equations that govern the temperatures. The gas flow analysis incorporates upwind differencing (Courant Method) in its solution scheme. Heat transfer relations for the inside of the boiler tube, with liquid preheat and nucleate boiling are considered. The outside tube convection coefficient uses correlations based on a cylinder in cross-flow. The model can use either average or local convection coefficients around the tube. The radiation heat transfer is modelled using a gray body analogy that gives a relationship between gray and black body radiation exchange. The model also can adjust the radiation heat transfer between one surface and another to account for attenuation caused by the gas. Radiation view factors from tube to gas and from tube to combustion gases is also determined for the selected geometry. Conduction through the refractory material and across tube walls has also be incorporated.

The model has been designed as a general purpose tool to evaluate physical geometries, different thermal properties and varying gas temperature and properties. The model also incorporates a calculational procedure which evaluates pressure drop across the tubes and estimates slag droplet collection efficiency on the tubes. Slag droplet size distribution can be input and initial work will use the size distribution expected from the fired coal pulverized to 70% passing 200 mesh screen.

The work during this reporting period is to validate a series of boiler-specific fabrication concepts against the overall design requirements. The design process is a series of trade-offs between boiler fabrication constraints and heat transfer/slag capture requirements. For ease of integration of the slag screen into the boiler wall, the tubes are formed by first removing the existing cyclone throat and then extending the existing boiler water wall tubes across the LNS Burner throat. The task became to select the optimum configuration for the slag screen within the allowable boiler wall geometry.

The task began initially by defining the design guidelines and establishing a set of process performance assumptions. Typical refractory installation guidelines were received from suppliers. Preliminary evaluations were performed based on these design guidelines and assumptions.
These preliminary calculations revealed that significant refractory thickness would be required to maintain the tube surface at 2300°F because the high heat flux to the 500°F water inside the tubes kept driving the surface temperature to well below the desired goal. A series of design studies were made to layout the best arrangement of the tubes with respect to the boiler wall and heat transfer considerations. The pressure drop across each design configuration and the resultant slag droplet collection efficiency also had to be checked.

Work continues on refining the physical characteristics of the tubes, including diameter, refractory thickness, operating surface temperature, pressure drop and resultant slag screen efficiency. The slag screen model and the design are nearly finished with completion of this task expected in February 1991.
4.0 BALANCE OF PLANT ENGINEERING

4.1 ARCHITECTURAL WORK

A study was made to determine final painting requirements for the Fuel Preparation Building and mechanical equipment.

The structural and miscellaneous steelwork was coated with an epoxy polyamide after fabrication and before delivery to the site. It was determined that this coating is suitable for all steelwork surfaces within the building envelope because service conditions are not corrosive and will not be detrimental to this particular epoxy. All outside surfaces which are exposed to ultra-violet light will require a finish coat of enamel because ultra-violet light can cause deterioration of the epoxy within five to ten years. All such exposed surfaces, including the steelwork supports for the bucket elevator and the screw conveyor to the limestone and additive silos, will have a finish coat of Kolorane U Series enamel.

All uninsulated piping and mechanical equipment which was treated with a light red oxide primer will be given a finish coat of standard enamel.

All finish coat paint will be applied after construction has been completed to avoid damage to the paint during construction activities and the need for subsequent touch up.

4.2 CIVIL AND STRUCTURAL DESIGN

Floor and roof drawings and elevations for the Fuel Preparation Building were finalized and issued for construction. External elevation drawings are shown in Figures 6 and 7. Design and drafting for miscellaneous steelwork in the building, such as girts, platforms, stairs, ladders and equipment supports were completed and drawings were issued for procurement, fabrication and installation.
Ongoing engineering support was provided to the field staff during erection of the Fuel Preparation Building and minor design and detailing changes were made to resolve problems as they occurred. A view of the topping out ceremony for the Fuel Preparation Building is shown in Figure 8.

A physical check was made of all areas of the existing plant and structures where new raceways, piping or equipment were to be added. This was done to identify potential interferences and to obtain sufficient information to check the capability of the existing structures to support the piping and raceway hanger loads, since no existing structural drawings were available. The structural evaluations were made and design and detailing of the hanger supports completed.

4.3 MECHANICAL DESIGN

The original coal delivery piping design for the LNS Burner required coal feed splits from one 12" diameter to six 5" diameter pipes. The design of the coal splitter assemblies had not been finalized at that time and it was assumed that the splitter location would be at the burner.

The coal splitter design eventually selected for the retrofit is orientated vertically with flow entering at the bottom and leaving from the top. Several straight pipe runs are required on the upstream side of the splitter to achieve a uniform distribution of flow. Because this pipe configuration could not be accommodated in the space available at the burner front, the coal splitter assemblies were relocated in the Fuel Preparation Building. The optimum route for the two sets of six 5" diameter fuel lines was selected by a combination of desk study and field reconnaissance and generally follows the route of the original 12" diameter feed pipe to the burner.

The relocation of the coal splitter assemblies to the Fuel Preparation Building increased by six times the length of fuel pipe between the riser and the burners. With butt welded pipe joints as in the original design and allowing for the reduction in diameter from 12" to 5", the cost would have increased by more than 3-1/2 times. After further study, a combination of
flanged and mechanically coupled joints was adopted. This will result in a saving in cost of approximately $20,000 and will permit periodic rotation of the pipe to ensure uniform wear.

4.4 ELECTRICAL DESIGN

The locations of electrical components and peripherals in the Fuel Preparation Building, such as control panels, terminal boxes and marshalling junction boxes, were reviewed to eliminate or minimize structural and piping interferences.

Cable tray drawings for the new and existing buildings were finalized from the site reconnaissance data and design sketches developed during the previous reporting period. These drawings were issued for procurement and installation.

The fire alarm system design for the Fuel Preparation Building was developed. Consideration was given to thermal and ionisation detectors in the building, but it was concluded that, because of the high ceilings and the open nature of the structure, neither type of detector would prove to be effective. The selected design includes manual pull stations and external alarm horns. Material requisitions were prepared for bid issue and procurement of the system.

The design of the public address system in the Fuel Preparation Building was completed. This system will utilize page/party line stations which are compatible with the existing system used in the Marion Power Plant. Material requisitions for this equipment were prepared for bid issue and procurement.

As part of the reassessment of the control scheme, modification drawings were prepared to identify all electrical power and control devices and associated circuits that would need to be modified, relocated or deleted. This activity required the revalidation of each existing plant circuit in relation to the overall retrofit design.
Ground system requirements for the Digital Control System were reviewed. Two ground systems will be required. The AC safety ground can be connected to the existing plant ground, but the system common ground requires a dedicated and isolated ground conductor from each common bus directly to the plant grid. These systems will meet the requirements of NEC Article 250 and will minimize the possibility of circulating currents.

Conduit routing drawings of the 480V circuits originating from the new MCC NH01 were completed and released for construction.

Prior to the relocation of the right half of MCC 1B at the burner front, a detailed study of the actual loads was performed. This was required to identify common plant loads that are fed from this MCC and need to be maintained while Unit 1 is shut down for the retrofit. After identification of these loads, an alternative source of power was located and connected to ensure continuity of supply.

Vendor drawings of major components were reviewed to ensure that adequate detail had been provided for the location of electrical and control devices, together with wiring and connection information.

4.5 INSTRUMENTATION AND CONTROLS

Preparation of the Instrument Index continued and additional data and information for various fields was added as it became available from review of the control system drawings and control equipment documentation.

Design drawings were prepared for the modifications required to the main control room console for addition of the control system CRT electronics and keyboards for operation of the DCS.

Instrument installation drawings showing connection details for transmitters, switches, primary elements, converters and field mounted devices were started and are still in progress. These drawings show installation details, types of equipment, lists of materials and details of accessory items.
The existing plant annunciator alarm points were reviewed for all functions required for operation of the LNS Burner retrofit. It was concluded that most of the existing balance of plant alarms would be used with the new system. The existing annunciator will be retained for ease of operation and the alarm points will be wired to the DCS for alarm printing and logging.

A review of the existing boiler protective interlocks was completed to determine the functions to be utilized with the new controls for the LNS Burner retrofit. The appropriate interlocks will be incorporated into the new system, which is designed to meet applicable sections of the NFPA standard covering boiler and burner operation.

4.6 PROCUREMENT

Technical specifications and material requisitions were prepared and bid packages issued for the following equipment, materials and services:

- Fuel Preparation Building girts, doors and platforms
- Fuel Preparation Building siding
- Fuel Preparation Building overhead door, roofing, roof hatch and louvers
- Air cannons for the limestone, additive and coal silos
- Silo level instrumentation
- Carbon dioxide instrumentation
- Steam temperature control instrumentation
- Boiler materials monitoring inspection
- Electrical bulk items
- Instrument calibration services
4.7 CONSTRUCTION AND INSTALLATION

Erection of the stack monitoring platform and installation of the sampling access ports and instrumentation (Figure 9) was completed in October.

Structural steelwork erection for the Fuel Preparation Building was completed. The installation of miscellaneous steelwork in the building was started and is still in progress.

Construction of the reinforced concrete foundation for the bucket elevator was completed and erection of structural steelwork to support the bucket elevator is in progress (Figure 10).

Replacement of the existing Unit 1 boiler floor tubes (Figure 11) and the refurbishment of ductwork insulation by SIPC started in November and is still in progress.

Relocation of the coal feeders (Figure 12) has been completed. The pulverizer (Figure 13), fuel transport blower (Figure 14) and air cannons for the limestone and additive silos (Figure 15) have been installed. Installation of the coal pipe and air tempering ductwork has started and is still in progress. The position of the coal separation cyclones is shown in Figure 16. Setting of the limestone silo is shown in Figure 17.

Burner related electrical dismantling and relocation was completed and instruments for the burner front control panel were removed for relocation. Removal of the existing control panels and wiring started in December in preparation for retrofit construction. Installation of the 480V load breaker and the 2400V switchgear breaker has also started and is continuing. Cable trays for the Fuel Preparation Building have been installed and work on other cable trays and conduit is in progress.
5.0 BOILER MODIFICATIONS

An inspection of Marion Unit #1 boiler was completed as part of the Materials Monitoring Program. The purpose of this inspection was to provide detailed information regarding the present condition of the boiler and determine any repairs necessary to assure operability and availability for baseload operation during the Demonstration Phase of the retrofitted plant. The scope of work of this inspection included visual inspection and ultrasonic non-destructive examination of the following areas:

- cyclone burners
- Floor and water wall tubing
- Furnace roof and penthouse area
- Dead air spaces in furnace casing
- Hangers, supports, braces, attachments
- Convection pass wall tube refractory
- Superheater and generating bank tube gross alignment or bowing

The results of the detailed inspection and assessment indicate that some areas of the boiler are in fair condition considering its age of service. Specific areas need repair and further inspection to ensure that the boiler can be reliably operated over the burner test program.

Severe tube thinning was determined from ultrasonic inspection on the exterior thickness of the waterwall tubing in the front of the boiler. The condition was the result of tube and attachment corrosion caused by rainwater entering the boiler casing and settling in the buckstay areas over the life of the unit. Major panels of the front wall tubing will require replacement. The floor tubing of the unit was found to have extensive thinning and will be replaced up to the entrance of the cyclone in the furnace area. A summary of the inspections and action to be taken is noted as follows:

Both cyclones show signs of significant tube thinning. The most severe thinning is located on the bottom half (3 o'clock to 9 o'clock) of both
cyclones. The amount of tube thinning in both cyclones averages approximately 15 to 20% from the originally supplied tube thickness. However, in the design of the cyclones, extra heavy wall tube (1-15/32" OD, 0.250 wall) was selected due to the expected tube wastage. For the 1-15/32" O.D. tubing, the code calculated minimum wall is only 0.060" thickness. Fabricating the cyclones with 0.250" wall tubing incorporates a large corrosion allowance into the design. Therefore, the average amount of tube thinning is not detrimental to providing a year of reliable service.

It should be noted that previous tube failures in the cyclone indicate that isolated problem areas do exist. While the lowest thickness reading was 0.170", lower wall thicknesses probably exist and may cause a few tube leaks during the next year or so of operation. These tubes will be repaired or replaced.

The U.T. survey taken of the front waterwall indicates that severe corrosion has occurred on the exterior (non-fireside) surface of the tubes. Some of the readings are below the calculated code minimum wall thickness of 0.102" for 2-1/2" O.D. tubes. Replacement of the affected area is required to remove those tubes which will probably fail during the next year of operation. As a minimum, the first 16 tubes in from the side wall (not including the areas of new tubing at the furnace corners installed by SIPC) will be replaced. The replacement tubes will extend from the tubes currently being installed, to just past the front wall to furnace roof tube bend. A view of the front wall tubes prepared for UT testing is shown in Figure 18.

The buckstays on the rear gas outlet duct are badly corroded and will be repaired or replaced. Two broken buckstays located on the front wall confirm concerns regarding the integrity of the supports. No significant limitations or effects on boiler operation is expected over the next year unless furnace pressure excursions occur. Most likely causes of downtime over the next year are possible fatigue failures at the buckstay/ tube attachments. The cyclic duty, external corrosion and attachment design create an environment conducive to fatigue crack growth. Past fatigue failures at these locations indicate that some of the existing attachment welds are in various stages of fatigue damage. Non-cyclic operation will
limit the number of failures which will occur over the next year of operation.

All of the pressure parts internal to the boiler furnace (superheater and generating bank, etc.) appear to be in good condition. No signs of damage which would cause reliability problems were noted. Damage to external parts of the boiler has been caused by flue gas leaking to the external surfaces of the boiler, then cooling and mixing with water and oxygen to produce a corrosive environment. Streaks of yellow in the deposits found on the corroded areas indicate that sulfur may have a major part in the problem. Repairing the leaks and prohibiting the corrosive environment from developing will have significant positive effects on the next year of boiler operation.

Broken refractory around the superheater tube roof penetrations and holes in refractory over the furnace roof tubes will be repaired. These repairs are necessary to prevent gas leaks to and excessive buildup of flyash in the penthouse. The additional weight of any flyash buildup in the penthouse may cause damage to the roof refractory and tubing.

Lagging and insulation over the furnace will be replaced including hanger rod seals and covers. Lagging joints will be weatherproofed using sealant. Repairing the lagging and insulation is not vital to a one year operation cycle since the lagging is primarily for personnel protection and weatherproofing.

All casing endorsing dead air spaces will be repaired. Each air space will be made air tight to prevent the intrusion of flue gases from the boiler and moisture from the outside. None of the observed corrosion in the dead air spaces is serious enough to affect the boiler’s reliability over the next year.

Gas outlet duct support systems need to be replaced (see Figure 19). Severe corrosion of the supports may lead to failure at any time. Holes in the ductwork should be patched to minimize the amount of escaping flue gas. Holes in the flue gas pressure boundary adversely affect the
performance of the boiler. Buckstay attachments along the rear and side walls (exposed to weather) will be inspected.
6.0 BASELINE TEST

6.1 INTRODUCTION

A series of boiler performance tests were conducted in October, 1990 on the Unit 1 of SIPC's Marion Station. These tests were called the Baseline Tests. The primary objective of the Baseline Test was to collect data from the existing plant that could provide a comparison after the LNS Burner retrofit. This comparison would confirm the effective low cost control of NOx and SO2 emissions provided by the LNS Burner. Further, these tests would provide operation characteristics of the Host Unit and some engineering design information that would minimize technical uncertainties in the application of the LNS Burner technology. The tests followed the Demonstration Test Plan; CDOE3010N as released for Baseline Tests and collected the data identified in Drawings M74-BA01-1 and 2.

6.1.1 Management of Baseline Test Program

The Project Management Plan, CDOE10102N, identified the responsibility and role of each participant in the Project. All Baseline test activity was monitored by the TransAlta Project Manager. Bechtel Corporation, reporting to the TransAlta Project Manager, developed the detail test plans, managed on-site activity, and coordinated the boiler operation and schedule with Southern Illinois Power Cooperative. Clean Air Engineering provided the independent services for data gathering and environmental monitoring. CAE also provided for waste product analysis. Riley Stoker Corporation provided services to gather and analyze the boiler performance data.

6.1.2 Pretest Activities

Pretest activities began with the arrival of the Boiler Performance and Environmental test teams at the site on October 15, 1990 and October 19, 1990, respectively. During this period, test instrumentation was installed, checked out, calibrated and tested in service. Craft support was provided throughout this as well as the actual testing phase of the Baseline test.
Earlier, test ports had been installed in the boiler walls by Riley to enable thermal mapping of the boiler internals.

Baseline tests could not be delayed any longer. The Baseline tests had been postponed several times due to TransAlta programmatic and budget issues. Test scheduling was strongly influenced by SIPC's load demand requirements. Unit 1 operation was scheduled on-line (with incremental loading as required) when SIPC's base loaded Unit 4 would be down for a two week annual maintenance outage. After this period, Unit 1 was to be removed from service for an extended period which could run until the LNS Burner installation was scheduled to commence.

On October 19, 1990, the Boiler Performance team performed a practice test run. During this activity it was discovered that the Unit 1 inspection ports could not be opened with the Unit 1 boiler operating (pressurized). As a result, it would be impossible to make the required boiler gas temperature probe traverses. Investigation disclosed that the aspirator nozzles were not installed in the inspection port assemblies and that a Unit shutdown would be required to install them. It was also determined that Unit 1 had developed a tube leak which was necessary to repair prior to the test.

6.2 BASELINE TESTING

6.2.1 Performance Test No. 1 - October 23, 1990

8500 PSIG Throttle Pressure;
900°F Main Steam Temperature;
Plant At 33.0 MW

On Tuesday, October 23, 1990, Unit 1 was on the line at 33.0 MW. Problems with the 1B Cyclone flame stability had been experienced prior to this time which required placing the oil fired ignitor in service to sustain stable combustion conditions. The ignitor was removed from service and adjustments were made to the tertiary air damper.
The rated test began at 10:30 a.m. and emissions and data gathering proceeded normally for over two hours. At this time the 1A Cyclone tripped twice in succession due to loss of coal flow. Operators were employed to rap the coal bunkers by striking them with 5 lb hammers to assist in maintaining continuous coal flow from the bunkers. This incident occurred after the completion of the second set and before the start of the third set of emissions testing and data collection, thus negating the need to repeat all or any part of a run. Testing was resumed and was completed after the Unit was again stabilized.

Slag was collected successfully during the rated test run, although a limited amount of material was lost through leakage and overflow from the slag catch tank. This leakage was estimated as minor and will be taken into account in test results.

At the conclusion of the performance testing, a "high excess air" test was conducted to determine the effects of additional excess air on stack emissions. Boiler exit O₂ levels were adjusted so that maximum superheater metals temperatures were not exceeded.

6.2.2 Performance Test No. 2 - October 24, 1990

850 PSIG Throttle Pressure;
900°F Main Steam Temperature;
50% MCR (17.0 MW)

For the intermediate load performance, testing was scheduled for 7:00 a.m. on Wednesday, October 24, 1990. Trouble was noted sustaining stable coal fire combustion conditions in the 1B Cyclone which required the use of fuel oil support fuel. This would inherently invalidate the test. As a result of this problem, the planned test at 75% MCR was aborted. Therefore, to take advantage of the tests crews and the day, it was decided to reduce the Unit load to the minimum load (50% MCR) test point. The 1B Cyclone was then removed from service and the half load test conditions (operating cyclone 1A at full load, 1B off line) were established and allowed to stabilize.
After being removed from service, inspection of the 1B Cyclone revealed a significant amount of slag buildup in the bottom and up the right hand side of the barrel adjacent to the cyclone inlet. The cause of the buildup was not verified, but was thought to be the results of either a tube leak or a mechanical problem with the tertiary air damper. The minimum load test was conducted without a disruption causing incident.

Improvements in the "slag catching" dumpster tailgate-sealing method, as well as a modified procedure, minimized the slag losses. The procedure was modified to batch dump the boiler slag tank two hours into the test, and again at the end of the test. This allowed the use of less sluice water and less slag loss due to dumpster overflow.

A "high excess air" test was also performed at the conclusion of the 50% test.

6.2.3 Performance Test No. 3 - October 25, 1990

850 Throttle Pressure;
900°F Main Steam Temperature;
75% MCR (25.0 MW)

Although unsure that this test could be accomplished, considering the problems with the 1B Cyclone, it was felt that if support fuel was fired in the cyclone over night, the slag buildup would be melted away. The expectation was that the testing could be completed without support fuel before the slagging and flame stability problem would reoccur. After the Unit was initially stabilized at 75% MCR, (both cyclones at low fire) start delays were encountered due to spurious combustion control upsets. Also, problems were noted with the stack gas sampling equipment to the Clean Air test equipment trailer. Two hours of the test were completed without incident, but at about that point in time an obvious change in the 1B Cyclone combustion condition was noted as flame colour changed from brilliant white with a steady flame to a generally orange-flickering state. Approximately 30 minutes later it was necessary to place the oil fire gun in service to keep the cyclone lit and maintain load. The intermediate load test
was then terminated as sufficient data was accumulated to accomplish project goals.

6.3 BOILER PERFORMANCE TEST

The boiler performance test was conducted in accordance with ASME PTC 4.1 (abbreviated form) by Riley Stoker at steady state operating conditions of minimum, intermediate and rated load.

The heat loss method was used to determine the boiler efficiency considering the following losses:

a. Heat loss due to dry gas.
b. Heat loss due to moisture in the fuel.
c. Heat loss due to H_{2}O from combination of H_{2}.
d. Heat loss due to combustibles in the refuse (unburned carbon).
e. Heat loss due to radiation. (The manufacturer's predicted value was to be used if the boiler insulation condition was acceptable, and/or the value determined from the ABMA radiation loss chart).
f. Heat loss due to sensible heat in slag.
g. Heat loss due to moisture in air.
h. Unaccounted-for losses.

Allowances for measurement and sampling errors for the full load test were determined in accordance with Paragraph 3.03.1 of ASME PTC 4.1 and the Table of Tolerances given on Page 27 of the code for the heat loss method. In calculating the boiler efficiency by the heat loss method, the flue gas temperature leaving the air preheater, corrected for leakage, was utilized. Approximately 1 hour was allowed to stabilize the unit at steady-state load conditions prior to obtaining test data. During the stabilization period and for the duration of the load tests, the boiler continuous blow down was valved out of service. Sootblowers were operated just prior to the stabilization and test period, and then remained idle until the completion of the tests.
During the load tests, coal samples were taken at the coal feeder inlet in accordance with PTC 3.2, Test Code for Solid Fuels and the analysis performed in accordance with ASTM D271. The sample(s) taken for ultimate analysis was composited and divided into two equal composite samples. One sample was analyzed by the testing laboratory and the other retained as a duplicate until the final results of the test have been reviewed and found acceptable. Separate samples were obtained for fuel moisture.

Temperature data throughout the boiler was gathered at the operating loads. Temperatures of the boiler wall tubes was measured by thermocouples welded to water tubes. The furnace outlet and superheater outlet was determined from an installed thermocouple grid.

6.3.1 **Boiler Performance Results**

The preliminary results are presented in Section 2.0 of this report. Initial evaluation of the carbon in the flyash showed excessively high carbon. The heat loss due to the combustible in refuse, calculated at 6.79%, was significantly higher than the original design value of 0.1%. This difference is a result of the high percent of carbon, 54.85%, as analyzed from the flyash samples. This data is probably incorrect and would cause error throughout the program. A reanalysis of the flyash has been ordered and is in work. Therefore, any data from the Baseline Test has been labelled preliminary and is subject to change.

During this test, the emissions test crew performed isokinetic particulate loading tests at the air heater gas inlet. This data and the analysis of carbon in the flyash samples taken from the boiler hoppers provided the means to calculate the flyash to slag ratio. The flyash to slag ratio was assumed to remain consistent for all boiler loads.

6.4 **MATERIAL MONITORING PROGRAM**

The existing boiler, air heater, and dust collection system component materials (as well as the retrofitted burner support system components and materials) require inspection to evaluate their behaviour in the LNS Burner combustion process.
The Unit 1 Boiler is nearly 30 years old. As required by the Demonstration Plan, Materials Monitoring consists of material inspection and the accumulation of Baseline data concerning the as-found condition of boiler pressure parts, refractory, ductwork, support, dust collection system, and air heater. The as-found material condition and data will be compared with inspection data accumulated from the same areas, at the completion of the project demonstration phase. The new components and materials specific to the LNS Burner, including new boiler tubing, will also be inspected and evaluated for corrosion.

Performance and physical condition of the equipment in the Material Monitoring Program noted during Operational Readiness Inspections and Maintenance Inspections completed prior to the Baseline performance test indicated that major maintenance items should be completed to assure plant reliability during the Demonstration Phase of the Project. This maintenance includes replacement of boiler tubing in the lower furnace and general repair of other items that are related to the program. This work is scheduled to be completed during the retrofit of the LNS Burner, but prior to start-up of the retrofitted plant. The material monitoring inspection will be accomplished after this work has been completed. This will assure that program objectives will be met documenting effect of LNS Burner on plant components. Any comparison with existing components that require replacement or extensive maintenance would not fulfill program objectives.

6.4.1 General Boiler Condition

The following boiler casing breaching and ductwork leaks were noted during Baseline testing and were taken into consideration in validation of data and test results:

a. Failures in the refractory seal between the furnace and penthouse existed which was evident by a deposit of ash that could be seen and the velocity with which it was being carried from the penthouse access door and from beneath the penthouse lagging in many areas.
b. Gas leakage from the upper section of the convection pass was apparent from the concentration of noxious fumes in general areas.

c. The breaching in the area of the regenerative air preheater hot gas inlet had a number of leaks.

d. The southeast corner of the mechanical flyash separator was a minor source of gas and ash leakage.

e. One convection pass manhold door leaked badly around its circumference.

f. One third of the steam coil air heater was not in service.

g. The inlet expansion joint on the east secondary metering venturi failed and leaked.

h. The boiler insulation and lagging was deteriorated in some areas.

6.5 ENVIRONMENTAL MONITORING

This Baseline Environmental Monitoring Program addressed the compliance, characterization, and supplemental monitoring requirements appropriate for atmospheric emissions, wastewater effluent, solid waste generation, and worker health and safety issues associated with TransAlta's LNS Burner Retrofitting of Utility Cyclone Boilers Demonstration Project.

Flue gas stack monitoring was conducted throughout the Baseline Program. This monitoring consists of NO\textsubscript{x}, SO\textsubscript{x}, O\textsubscript{2}, CO\textsubscript{2}, and opacity and was monitored throughout the entire program. CO and O\textsubscript{2} measurements taken from the boiler outlet was used for performance testing. O\textsubscript{2}, CO, and CO\textsubscript{2} determine carbon utilization and CO and O\textsubscript{2} data are used to normalize SO\textsubscript{2} and NO\textsubscript{2}.

Wastewater monitoring conducted during the LNS Burner demonstration project was limited to slag and flyash sluice water effluent from Unit 1. The demonstration project was not expected to impact other water flows from the plant.
The flyash and bottom ash sluice water systems for each unit feed a common header (one header for each system). The sluice water systems are manually controlled. During the full load Baseline Test, two sluice water samples were collected and analyzed. Samples of the raw sluice water as well as from the slag and flyash handling systems were collected each time. The following approach ensured that representative sluice water samples were obtained: prior to obtaining the sample, the slag and flyash hoppers for Units 2, 3 and 4 were checked to ensure that they did not need to be emptied while the Unit 1 sample was being taken. After the Unit 1 sluice water systems were started, the technician waited at least 15 minutes before collecting the sample to ensure that the sluice water system had been flushed.

The sluice water samples from all three of the sampling points (raw sluice water, flyash pond and bottom ash pond) were tested for the characteristics required in the program.

The sample of the sluice water collected from the upstream side of the sluice water system were analyzed to ensure that outside factors such as seasonal variations in water quality did not impact the data.

The flyash and slag for Baseline Testing was collected and analyzed mainly to determine the suitability of different disposal options and to develop a material and sulfur balance.

Slag and flyash samples collected during the Baseline, full load testing was analyzed for their composition, including trace elements. Analyses of slag and flyash samples from the LNS Burner demonstration runs included determination of their composition, leachability of common ions, and whether the ash characteristics would meet the hazardous waste criteria under the Resource Conservation and Recovery Act (RCRA).

Particulate flows and particle samples to determine flyash morphology, size distribution, grain loading, and resistivity were taken at the inlet of the mechanical collector. Grain loading at the inlet and outlet of the electrostatic dust collection system was also measured to determine the effect of the LNS Burner on ESP flyash collection efficiency.
The leachability of common cations and anions determine the inertness of the LNS Burner slag and flyash and, consequently, the suitability of disposal options. The leachate procedure will be the Toxicity Characteristic Leaching Procedure (TCLP) from Appendix I to 40 CFR 268. The leachate was tested using test procedures identified in 40 CFR 136.3.

Slag and flyash generated from the combustion of coal are currently classified as "solid wastes which are not hazardous wastes" by EPA (40 CFR 261.4(b)(4)). Some disposal sites, however, may require that the ash be analyzed regardless of this exemption. Therefore, the flyash and slag samples will be analyzed per 40 CFR 261.24.

Slag samples were collected at the same time as slag sluice water samples. The sluice water was quickly decanted from the slag samples, and the samples allowed to dry. A composite flyash sample was prepared from the dust collection system prior to the operation of the flyash sluice water system. Collection in this manner assured that the sluice water samples and the ash samples are representative of the same operating conditions. The slag and flyash samples were split, and one will be stored in a sealed container until testing has been successfully completed.

Slag and flyash samples were collected during other load tests. Results were used in determining boiler efficiency as part of the boiler performance testing.
7.0 BOILER MAINTENANCE

The maintenance program for the Demonstration Phase of Marion Unit #1 was established from data provided by SIPC. The program was based on maintenance history for a single 33MW unit averaged from actual data for all three Marion 33MW units. All have been operated recently either for peaking service for replacement power or when Unit #4 was shut down. Recent performance of Unit #1 observed by site personnel and development of a list of known equipment and other defects which directly effect both peaking and baseload operating capability indicate that preventative maintenance will be required prior to commencement of Phase III. Additional funds will be required for this pre-demonstration maintenance.

The following is a summary of tasks associated with preventative maintenance program to be accomplished prior to commencement of Phase III - Demonstration Testing:

- Repack the 1st valve (root valve) and critical valves in key piping systems. Repack 1st and 2nd valves to level, flow and pressure transmitters and replace instrument piping as necessary.
- Inspect Unit 1 balance of plant heat exchangers and chemically/mechanically clean as necessary.
- Replace high pressure drain valves (2" and under) as necessary.
- Load test and replace two main steam line hangers.
- Check out, calibrate and tune existing unit field instrument.
- Inspect and rebuild key control valves.
- Load test/replace two main steam pipe hangers and check sway suppressor.
- Set the drum and superheater safety valves.
- Repair the broken personnel protection safety locking devices on the electrostatic precipitator.
- Repair the known boiler and multi-clone casing and breaching leaks.
- Replace defective insulation and lagging and reinsulate uninsulated areas of the boiler breaching, casing and ductwork.
- Repair the superheater drain piping failures - may involve the replacement of approximately 160' of 1-1/2 schedule 80 piping.
- Replace the boiler blowdown tank.
- Replace the defective bushing on the No. 3 electrostatic precipitator field.
- Miscellaneous maintenance to local power supplies, plant lighting, and electrical controls. The above maintenance items will be completed in parallel with retrofit construction in Phase II of the project.
8.0 TECHNOLOGY TRANSFER

A paper entitled "Cyclone Retrofit Demonstration Program with TransAlta's Low NOx/SOx Burner" was presented at the Joint Power Generation Conference in Boston, Massachusetts in October, 1990 by William L. Fraser, President of TransAlta Technologies, Inc. and Dr. Gerard G. Elia, Project Manager, U.S. Department of Energy. A copy of the paper is attached as Appendix A to this report.

A similar paper was presented by Keith Moore, Vice-President of TTI, at the French/American Natural Gas and Coal High Performance Technologies Symposium in Chicago, Illinois in November, 1990. The symposium was sponsored by the Gas Research Institute of Gas Technology, Southern Illinois University Coal Research Center and the French Trade Commission.
9.0 WORK PLANNED FOR NEXT PERIOD

The following work is scheduled for execution during the next reporting period from January 1, 1991 to March 31, 1991:

Technical Design

- Structural assessment to check LNS Burner fabrication drawings against design and operating requirements
- Complete slag screen modelling and design
- Finalize boiler modelling
- Continue detail electrical and I&C design
- Finalize DCS programming
- Finalize Baseline Test Report
- Prepare presentations for Progress Review #1
- Complete installation of miscellaneous steelwork in the Fuel Preparation Building
- Erect siding and roofing and install overhead door, roof hatch and louvers for Fuel Preparation Building
- Complete pre-operation inspections of the boiler and other major items of plant equipment
- Carry out the preventative maintenance program on the boiler and balance of plant
- Complete erection of structural steelwork supports and install bucket elevator
- Continue electrical installation
FIGURES

1 - 19
Figure 1
Schematic of LNS Burner
Boiler Interface
Figure 3
Temperature Isolines at Superheat Region
Figure 4
Temperature Profile at Superheat Region
Figure 5
Slag Screen
Tube Layout
Figure 9
Stack Monitoring Platform
Figure 14
Fuel Transport Blower
Figure 15
Air Cannons
Figure 16
Coal Separator Cyclones
Figure 17
Setting Limestone Silo
Figure 18

Boiler Wall Tubes
Cyclone Retrofit Demonstration Program
with TransAlta's Low NO\textsubscript{X}/SO\textsubscript{X} Burner

By
Gerard G. Elia, Ph.D., P.E.
Project Manager, U.S. Department of Energy
and
William L. Fraser, P.E.
President, TransAlta Technologies, Inc.
at
1990 Joint Power Generation Conference

The U.S. Department of Energy, under the Innovative Clean Coal Technology Program, in concert with TransAlta Technologies, Inc., a nonregulated subsidiary of TransAlta Resources Investment Corporation and TransAlta Utilities, in Calgary, Alberta, Canada, will demonstrate the retrofit and operation of the Low NO\textsubscript{X}/SO\textsubscript{X} (LNS) Burner on a 33-MW utility cyclone boiler at Southern Illinois Power Co-operative in Marion, Illinois.

The LNS Burner has the potential to control both SO\textsubscript{2} and NO\textsubscript{X} emissions from cyclone boilers at a lower cost than any other known technology. The experience gained from this demonstration program is expected to prove the LNS Burner, thereby providing coal fired boilers a design option for extended life with the ability to meet acid rain environmental legislation.

Introduction

Operating cyclone-design boilers comprise about 26,000 megawatts (MW) of generating capacity in the United States. The typical cyclone boiler fires a high-sulfur bituminous coal at high temperature, which results in high SO\textsubscript{2} and NO\textsubscript{X} emissions. These boilers are generally older mature units, grandfathered with respect to emission control regulations. The net result is that this relatively small fraction of coal-fired utility generating capacity is responsible for a disproportionate share of total utility boiler emissions.

The U.S. Congress is expected to pass new environmental regulations to control SO\textsubscript{2} and NO\textsubscript{X} from all coal-fired boilers. But it is not economical to fit conventional emission control equipment to the older cyclone units. What is needed, if these units are to be kept in service, is a low-cost retrofit option. The Low NO\textsubscript{X}/SO\textsubscript{X} (LNS) Burner may be this option.

The LNS Burner's combustion process operates at very high temperatures similar to the cyclone and produces a similar slag product. Furthermore, the LNS Burner demonstrates strong control of both SO\textsubscript{2} and NO\textsubscript{X} emissions during the combustion process. The retrofit costs are in the range of one-half that for wet scrubbers. Therefore, the LNS Burner may offer a low-cost retrofit option for utility cyclone boiler emission control programs and likely extend the economic life of cyclone units.

Clean Coal Demonstration Program
A full-scale demonstration of the LNS Burner retrofit on a cyclone boiler will be conducted under the auspices of the U.S. Department of Energy (DOE) Clean Coal Technology Program. The TransAlta project—Low NO\textsubscript{X}/SO\textsubscript{X} Burner Retrofit for Utility Cyclone Boilers—was selected for
negotiation under the second round solicitation Program Opportunity Notice DE-PS01-88-FE-61530.

The demonstration program is estimated to cost $16.3 million with a 1992 target date for completion. DOE will manage the project from the Pittsburgh Energy Technology Center (PETC) in Pittsburgh, Pennsylvania. Participants include:

- TransAlta Technologies, Inc. (TransAlta Resources Investment Corporation)
- Illinois Coal Development Board, through the State of Illinois Department of Energy and Natural Resources
- The National Rural Electric Cooperative Association (NRECA), through its Cooperative Research Committee. NRECA will be represented by Associated Electric Cooperative, Inc., of Springfield, Missouri.
- The Electric Power Research Institute, Palo Alto, California.
- Baltimore Gas & Electric, Baltimore, Maryland.

The project will be conducted at Southern Illinois Power Cooperative’s Marion plant on unit 1, a 33-MWe cyclone boiler.

The Clean Coal Technology Program is a jointly funded effort between government and industry to move the most promising advanced coal-based energy technologies from the R&D stage into the commercial marketplace. The Clean Coal effort sponsors projects that are different from DOE’s traditional R&D programs. The R&D projects center on relatively long-range, high-risk, high-payoff technologies in which DOE provides most or all of the funding. In contrast, the goal of Clean Coal projects is the demonstration of the commercial feasibility of the most promising advanced coal-based technologies that have already reached the proof-of-concept stage.

The Clean Coal projects are jointly funded endeavors conducted as cooperative agreements between the government and the private sector in which the industrial participant contributes at least 50% of the total cost of the project.

To date, DOE has selected six projects under three separate competitive solicitations covering a variety of advanced coal-based technologies. Two more solicitations are planned, with the total program exceeding $2.5 billion in federal procurement funds. These demonstrations are chosen at a scale large enough to generate appropriate data from design, construction, and operation such that the private sector may judge the commercial potential for the technologies. The Clean Coal Technology Program promises to provide information to the public to demonstrate the technological effectiveness, the commercial viability, and the environmental safety of the advanced coal-based systems. When the Clean Coal Technology Program is completed, the public will have at its disposal a wide range of technical, economic, and operational data to reduce the uncertainties of deploying these technologies in commercial-scale applications.

Cyclone Boiler Designs

Cyclone-fired boilers are used widely for generating steam, primarily in large electric power plants. Cyclone-fired boilers comprise only 9% of the total coal-fired steam generating capacity in the United States. However, as cyclone boilers are major sources of NOX, they contribute nearly 20% of total NOX emissions from all coal-fired utility boilers. Three states, Illinois, Missouri, and Indiana, account for nearly half of the total cyclone steam capacity and one-third of the boilers.1
The cyclone furnace tends to maintain a stable flame over wide operating ranges. Once the furnace is lit-off and reaches operating temperature, a flame-out is unlikely. Flame stability is maintained even at low excess air. Units typically operate at a carbon loss of less than 0.1% and can reject a major fraction of the coal ash as a slag product upstream from the boiler. Consequently, combustion efficiencies are very high, and the amount of ash that must be handled by the baghouse or electrostatic precipitator (ESP) is only about 25% of that of pulverized coal (PC) fired units.

Since most cyclone units were built before emission regulations were promulgated, they have been grandfathered with respect to pollution control regulation and very few employ scrubbers for SO₂ control. Baseline emissions from cyclone boilers are summarized in Ref. 1. The emissions of SO₂ reflect the sulfur in the coal being burned, with the highest emissions from high-sulfur bituminous-coal-fired units.

The cyclone generates high NOₓ emissions. The data indicate that at full load none of the cyclone units was able to meet the U.S. NSPS for NOₓ (for bituminous coal, 0.6 pound per million Btu [lb/MBtu]). In general, the cyclone's average full-load NOₓ emissions for bituminous coal is 1.44 lb/MBtu.  An ESP is generally used to control particulate emissions.

Project Host Site—Southern Illinois Power Co-operative

Southern Illinois Power Co-operative (SIPC), located on the 2,300-acre Lake of Egypt near Marion, Illinois, completed its 25th year of service in 1988. The Marion plant is SIPC's only generating facility, with a total installed capacity of 272 MW. The plant includes units 1, 2, and 3, each a cyclone boiler rated at 33 MW. These units were placed in service in 1963. Unit 4, a 173MW cyclone boiler, was placed in service in 1979. Unit 4 carries the system baseload. Units 1, 2, and 3 are normally on cold standby and are used during higher-load winter and summer peak periods. The 33-MW unit 1 was selected for the retrofit demonstration.

Project Fuel—Marion Station Coal

The coal currently being fired at SIPC is a blend of high-sulfur (3.5%) bituminous Illinois coal and mining waste material. Coal is supplied from both surface and deep shaft mines year round. The waste material is commonly referred to as "carbon." This material is obtained from old mining operations. It was initially screenings and/or coal washer rejects, which at that time were unprofitable to market. In 1988, approximately 651,000 tons of fuel were delivered at an average cost of $17.55 a ton.

Project Cyclone Boiler—Marion Station Unit 1

Unit 1 is a Babcock & Wilcox front-wall-fired cyclone two-drum pressurized-furnace rated at 33 MW similar to that shown in Figure 1. The two cyclone burners, fired with crushed coal, are rated at 200 MBtu/hr each.

The horizontal cyclone burners on Marion unit 1 are about 7 ft in diameter by 9.5 ft long. The cyclone burner walls and reentrant throat are fabricated from water-cooled tubes. The tubes are studded and coated with refractory for protection from the high heat fluxes in this region. Crushed coal is introduced centrally through a burner along with tertiary air and immediately swirled by the incoming tangential primary air input at the head end of the cyclone. Secondary air is introduced downstream tangentially into the cyclone barrel.

1 Applicability of NOₓ Combustion Modifications to Cyclone Boilers (Furnaces), EPA Report No. EPA-600/7-77-006, Jan 1977.
Combustion occurs primarily along the chamber wall zone in the mixture of slag and coal. The slag formed flows down the chamber wall and passes into the boiler through a key slot that is located in the lower portion of the cyclone boiler back wall. The reentrant throat is designed to minimize slag carryover in the gas stream entering the boiler. Typical slag (bottom ash) rejection rates are about 60%. Maintaining high combustion temperatures is critical to achieving proper slag flow.

The only emissions control criteria are for SO₂ and particulates; no control requirements are currently imposed for NOₓ. The present SO₂ emissions are determined by monitoring the maximum sulfur content in the coal. Actual SO₂ and NOₓ emissions from unit 1 are not now measured.

LNS Burner

The LNS Burner was conceived in 1979 as the result of theoretical combustion work done at Rockwell International. This theory predicted that both the sulfur and the nitrogen compounds formed from burning coal can be projected to be reduced to nearly zero in the combustion step. A series of concept verification tests followed by prototypical burner tests have verified the underlying theory of the LNS Burner. TransAlta Resources Investment Corporation, a non-regulated subsidiary of TransAlta Utilities Corporation located in Calgary, Canada, acquired the LNS Burner from Rockwell in 1986. TransAlta Technologies, Inc., has now been formed to undertake the task of commercializing the technology for the utility industry.

Classed as a slagging combustor, the LNS Burner involves high-temperature fuel-rich combustion for the control of both SO₂ and NOₓ. High-sulfur bituminous coal, mixed with limestone, is burned in a refractory-lined air- and water-cooled chamber. Using one-half of the total combustion air, the burner creates a hot fuel-rich gas. During combustion, the fuel sulfur is captured by the calcium from the limestone and is retained as a solid in the melted coal ash. Nitrogen chemically bound in the coal is converted to harmless molecular nitrogen. All of these operations are carried out in the burner. No solids or other fuels need be injected into the furnace, and no flue gas scrubbing is necessary.

LNS Burner/Cyclone Retrofit Configuration

The schematic of Figure 2 shows those new components required for the LNS Burner retrofit. Most of the major existing components in the plant will continue to be used, such as the coal bunkers and weigh-belt feeders, the ID fan, and the cyclone boiler. Generally, modifying the cyclone plant to fit the LNS Burner will require only:

- Modifying the cyclone furnace section with the LNS Burner.
- Reworking the coal preparation and conveying system with a coal pulverizer in place of the coal crusher.
- Providing a silo and metering system to add limestone or other additives to the coal.

LNS Burner Application

In the LNS Burner/cyclone boiler retrofit configuration shown in Figure 3, the LNS Burner will modify the front of the existing cyclone burner. Each LNS Burner is sized for 200 MBtu/hr, firing approximately 8 tons/hr of coal, the same as the existing cyclones. The as-received coal is conveyed from the existing bunkers and mixed with limestone to provide a Ca/S ratio of 2:1. These solids are then fed to the coal pulverizer. The pulverized coal and limestone are then air conveyed to the LNS Burners.

The existing cyclone throat, consisting of studded refractory-coated water-wall tubes,
will be removed. To increase the slag removal efficiency, a new slag screen assembly of staggered tubes, vertically traversing the opening, will be installed. The heat flux on these tubes is expected to be the same as that on the existing cyclone throat tubes. As the slag droplets collect on the screen, the slag drains to the slag tap located in the boiler’s insulated lower section. With the high-efficiency LNS Burner slag screen in place of the cyclone throat, an estimate of the new ash load shows that even with the increased quantity of ash, the fly ash load is expected to be lower. The slag quantity for disposal, however, will double.

The clean hot gas exiting the LNS Burner will be burned with final excess air in the boiler to obtain full heat release from the coal. It is in this step that care must be taken to prevent the formation of new thermal NOX.

LNS Burner Expected Performance

The LNS Burner/Cyclone Retrofit demonstration is expected to provide an SO2 reduction of 70% (with 90% as an ultimate goal) and very low NOX emissions (0.2 lb/MBtu). The thermal energy delivered to the boiler by the two 200-MBtu/hr LNS Burners is adequate to generate 335,000 lb/hr of steam with superheat to 905°F at 875 psig.

It is expected that the boiler efficiency will be nearly the same as before the retrofit, only affected by the minor heat loss from the increased quantity of slag. As a result, the gross heat rate will show a small increase. The estimated original and modified boiler performance analysis is presented in Table 1.

Cost Review

An assessment was made of the engineering, procurement, and construction (EPC) and the operation and maintenance (O&M) costs on a selected 500-MW cyclone boiler. This unit operated on a medium-sulfur coal. Generally, most application studies indicate that the LNS Burner’s cost is a very minor part of the total site-specific retrofit costs. Modifications to the boiler and other auxiliary systems result in the major retrofit costs. For the 500-MW unit, the total retrofit cost was $130/kW. The O&M cost (primarily for limestone) was $6.5 million per year. As a further comparison, an additional study was compiled from the Electric Power Research Institute (EPRI) and DOE publications to evaluate a wet limestone scrubber and a selective catalytic reduction (SCR) system for similar emissions control performance. Tables 2 and 3 (assumptions and references) summarize the results.

Also provided in Table 2 are the estimates comparing the LNS Burner and other candidate technologies when applied to a new plant. The EPC and O&M costs for a new 300-MW PC-fired plant built with conventional low NOX burners and no SO2 emissions control are listed to provide the base costs. The added costs for emissions control technology and its operation are shown for comparison. Note that these data represent order-of-magnitude costs to evaluate various alternatives. The data neither provide nor are intended to be used to determine the absolute cost of a specific technology. It is clear, however, that the LNS Burner promises a low-cost option for emissions control.

Conclusions

The key problem for the utility industry is and has been to identify a cost-effective emission control technique for coal-fired boilers. There are many emission control processes available, but for the older cyclone plants in particular, the remaining-life economics limits the affordable options, short of decommissioning.

TransAlta’s goal is to demonstrate the LNS Burner technology as a viable option for the
cyclone boiler as soon as possible. This aggressive schedule must then continue with larger-scale utility demonstrations, thereby providing a proven, cost-effective emissions control option in the face of pending environmental legislation.

Acknowledgments

TransAlta Resources Investment Corporation, Dykema Engineering, Bechtel Power, and Riley Stoker along with the cooperation of Southern Illinois Power Co-operative, participated in a Cyclone Retrofit Study Operating Committee formed of representatives from utility cyclone owners. The following organizations sponsored this work and assisted this study with their expertise and guidance:

Baltimore Gas & Electric Company
Union Electric Company
Wisconsin Power & Light Company
Electric Power Research Institute.

Disclaimer

References in this paper to any specific commercial product, process or service is made to facilitate understanding and does not necessarily imply its endorsement or favoring by the United States Department of Energy.
Figure 1. General View of a Cyclone Boiler and Convection Pass
Figure 2. LNS Burner/Cyclone Retrofit Schematic

Figure 3. LNS Burner/Cyclone Boiler Retrofit
Table 1. Estimated Boiler Performance

<table>
<thead>
<tr>
<th>Marion Unit 1</th>
<th>Original Design</th>
<th>LNS Burner</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam flow (lb/hr)</td>
<td>335,000</td>
<td>335,000</td>
</tr>
<tr>
<td>Coal Flow (lb/hr)</td>
<td>37,000</td>
<td>36,600</td>
</tr>
<tr>
<td>Additive (lb/hr)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Limestone</td>
<td>0</td>
<td>6350</td>
</tr>
<tr>
<td>Other</td>
<td>0</td>
<td>1750</td>
</tr>
<tr>
<td>Emissions at the stack (lb/MBtu)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>SO₂</td>
<td>5.85</td>
<td>1.76</td>
</tr>
<tr>
<td>NOₓ</td>
<td>1.35</td>
<td>0.2</td>
</tr>
<tr>
<td>Particulates</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Opacity (%)</td>
<td>&lt;30</td>
<td>&lt;30</td>
</tr>
<tr>
<td>Waste Disposal (lb/hr)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Slag</td>
<td>3760</td>
<td>9420</td>
</tr>
<tr>
<td>Fly Ash</td>
<td>2500</td>
<td>2320</td>
</tr>
<tr>
<td>Stack Emissions</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>Ash tapped as slag (%)</td>
<td>60</td>
<td>80</td>
</tr>
<tr>
<td>Boiler efficiency (net)</td>
<td>88.45</td>
<td>88.05</td>
</tr>
<tr>
<td>Technology</td>
<td>Emission Control (%) (SO$_x$/NO$_x$)</td>
<td>EPC$^b$ Cost$^c$ ($/kW$)</td>
</tr>
<tr>
<td>------------</td>
<td>------------------------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td>Cyclone retrofit—500 MW plant</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Low NO$_x$/SO$_x$ Burner</td>
<td>90/80</td>
<td>130</td>
</tr>
<tr>
<td>• Wet scrubber with SCR$^d$</td>
<td>90/80</td>
<td>320</td>
</tr>
<tr>
<td>New 300-MW PC plant (with low NO$_x$ Burners)</td>
<td></td>
<td>1150</td>
</tr>
<tr>
<td>Added cost for emissions control</td>
<td></td>
<td></td>
</tr>
<tr>
<td>• PC plant with scrubber</td>
<td>90/50</td>
<td>170</td>
</tr>
<tr>
<td>• PC plant with scrubber and SCR</td>
<td>90/80</td>
<td>320</td>
</tr>
<tr>
<td>• Low NO$_x$/SO$_x$ Burner</td>
<td>90/80</td>
<td>5</td>
</tr>
<tr>
<td>• Fluidized bed with SCR$^d$</td>
<td>90/80</td>
<td>175</td>
</tr>
<tr>
<td>• IGCC$^e$</td>
<td>90/80</td>
<td>350</td>
</tr>
</tbody>
</table>

$^a$These data have been compiled and factored principally from EPRI and DOE publications. The data represent order-of-magnitude costs that may be useful for comparisons of various alternatives but not for absolute costs of the specific technology.

$^b$EPC—engineering, procurement, construction.

$^c$Order-of-magnitude costs adjusted to June 1988 dollars.

$^d$SCR—selective catalytic reduction (required to achieve 80% NO$_x$ removal).

$^e$IGCC—integrated gasification combined cycle.
Table 3. Assumptions and References Underlying Table 2

<table>
<thead>
<tr>
<th>Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Capital costs are not site specific. Economic life is taken to be 30 years.</td>
</tr>
<tr>
<td>2. Operating costs are based on EPRI data published in Refs. 2 and 8 and exclude fuel costs. SCR O&amp;M costs include replacing the catalysis bed after 3 years at 2/3 the cost of the original installation and include nominal costs for NH₃ at $400/MW·year. SCR hazardous waste disposal costs have been excluded. O&amp;M costs also include (1) scrubber power consumption at 2% gross power at $0.05/kW·hr and (2) IGCC oxygen power consumption at 11.5% gross power at $0.05/kW·hr.</td>
</tr>
<tr>
<td>3. New plant costs were obtained from Refs. 2 and 3. Costs for AFDC (interest during construction), start-up, inventory, and land costs were backed out of the data so that all costs represented the basic EPC costs. EPRI costs were factored from 200-250 and 500 MW plants to obtain costs for a 300-MW plant. December 1985 EPRI costs were escalated by 2% for 1986, 2% for 1987, and 1% for half of 1988.</td>
</tr>
<tr>
<td>4. Repowering costs are based on DOE information (Ref. 5). The 500-MW unit in the reference has been factored and escalated in the same manner as used for new plant costs.</td>
</tr>
<tr>
<td>5. Retrofit costs are from estimates prepared for TransAlta's DOE clean coal proposal (Ref. 7) and from data in Ref. 4 that have been factored and escalated.</td>
</tr>
<tr>
<td>6. EPRI data basis:</td>
</tr>
<tr>
<td>Pulverized coal (PC) steam cycle conditions are 2400 psig, 1000°F/1000°F. The steam generator is rated at 2620 psig and 1005°F at the superheater outlet.</td>
</tr>
<tr>
<td>Circulating fluidized bed (CFB) steam-cycle conditions are 1990 psig, 1000°F/1000°F. The steam generators are rated at 2400 psig and 1000°F at the superheater outlet. The 300-MWe CFB comprises two 150-MWe combined units, forming one plant.</td>
</tr>
<tr>
<td>IGCC design and cost are based on a prototype full-heat-recovery process.</td>
</tr>
<tr>
<td>7. Low NOₓ/SOₓ Burner costs are assumed to be the same as conventional PC burner costs.</td>
</tr>
<tr>
<td>8. Coal-burning applications use Eastern bituminous coal (3.5% sulfur by weight).</td>
</tr>
<tr>
<td>9. An SCR price of $150/kW for the PC and cyclone plants was obtained by escalating the high range of the EPRI data (German currency rates) at 10%/year for 2 years. An SCR price of $75/kW for the fluidized bed plant was obtained by similarly escalating the low range (less NOₓ to be removed) of the EPRI data.</td>
</tr>
<tr>
<td>10. Flue gas desulfurization (FGD) costs are based on Bechtel's CT-121 process and are escalated to present dollars from Ref. 6.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. EPRI, <em>ECS Update, Summer 1987</em>, No. 9, Environmental Control System.</td>
</tr>
<tr>
<td>7. Bechtel/TransAlta, submittal to DOE (DE-PS01-88FE61530, Vol. II) and associated estimate.</td>
</tr>
<tr>
<td>8. EPRI projection for a mature IGCC facility, October 1987.</td>
</tr>
</tbody>
</table>